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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)

**COMMENTS AND RESPONSES TO QUESTIONS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)**

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Dated: September 5, 2014

I. INTRODUCTION

Pursuant to the preliminary schedule in Rulemaking (R.) 14-08-013, Pacific Gas and Electric Company ("PG&E") provides the following comments and responses to the questions presented in Section 3.1 of the Rulemaking.

PG&E's comments on the scope, schedule and other procedural issues in the proceeding are provided in Section II, below.

PG&E's response to the questions presented in Section 3.1 of the Rulemaking are attached to this pleading as Appendix A.

II. EXECUTIVE SUMMARY

PG&E commends the Commission and Commission staff for initiating this Rulemaking to provide timely guidance to the utilities for their proposed distributed resources plans required to be filed at the Commission by July 1, 2015 pursuant to Assembly Bill (AB) 327 and Public Utilities Code Section 769. PG&E encourages the expanded use of distributed resources to meet customers' preferences and avoid the need for costly distribution upgrades and other distribution system costs. PG&E also supports the streamlining of utility tariffs and procedures in order to reduce the time it takes customers and other owners and operators of distributed resources to interconnect distributed resources safely and reliably to PG&E's distribution grid. To that end, PG&E has enhanced its interconnection and distribution planning procedures over the last few years, and as a result PG&E has one of the fastest cycle times in the nation for processing distributed generation interconnection requests.

PG&E looks forward to continuing to explore and implement additional improvements to its distributed resources programs and processes through the transparent and objective proceeding initiated by this Rulemaking. The combination of collaborative stakeholder workshops and written comments and reports envisioned by the Rulemaking will provide an open and objective opportunity for all interested parties to provide input on the content and scope of the required distributed resource plans.

As discussed in more detail in the response to the Rulemaking's initial questions, PG&E recommends that the Commission in this pre-February, 2015 phase of the Rulemaking focus first on establishing a common understanding of the capabilities of each utility's existing electric distribution system and the processes by which current levels of distributed resources are integrated by the utilities into the system through distribution planning and utility system investments. As the *More than Smart* paper recommends, this common understanding should include an evaluation of the ability of the existing distribution system and distribution planning process to accommodate a reasonable range of projected distributed resources, and an assessment of methods and projects to enhance that process where improvements are identified.

PG&E also recommends that the Rulemaking at this early stage provide an inventory of existing tariffs, utility procedures, customer programs and operating protocols that affect the timely integration of distributed resources at all relevant points on the electric distribution system. This inventory should also include a discussion of where the existing tariffs and procedures may be perceived to act as barriers to the development and integration of distributed resources under various scenarios of market penetration and customer needs, and how those barriers can be removed.

Finally, the Rulemaking should evaluate and establish a consistent methodology for calculating the costs and benefits of distributed resources at various locations on the distribution systems. Then, upon Commission approval of the utilities' DRPs, the utilities' respective General Rate Case and tariff filings will include prospective investments in the distribution systems that may enhance the benefits provided by distributed resources as well as streamline the processes for integrating distributed resources into the grid.

PG&E recognizes that this agenda is an ambitious one in light of the procedural schedule and preliminary scope of this proceeding. However, PG&E believes that if the Commission and interested parties focus on these initial tasks, the quality and usefulness of the distributed resource plans filed next July will be significantly enhanced. PG&E looks forward to actively participating in and supporting this Rulemaking to achieve these goals.

III. PRELIMINARY COMMENTS ON SCOPE, SCHEDULE AND OTHER PROCEDURAL ISSUES

PG&E appreciates that the preliminary scope and schedule of the Rulemaking recognize that AB 327 provides for a two-step process for considering utility investments to improve the integration of distributed resources into electric distribution planning processes based on the avoided costs and benefits of the distributed resources. The first step is the filing and Commission review and approval of utility distributed resource plans filed by July 1, 2015, and the second step is review of any proposed utility investments in the utilities' General Rate Cases pursuant to the approved plans. (Public Utilities Code Section 769(b), (d).) This statutory process is very similar to the process used by the Commission to review the utilities' Smart Grid Deployment Plans under Public Utilities Code Section 8360, which also adopted a two-step process under which the utilities first filed and the Commission approved overall Smart Grid plans, and then any investments or expenditures for individual projects under the approved plans are reviewed separately in the utilities' general rate cases or other individual applications. (See D.10-06-047). To that end, the Rulemaking provides for a preliminary phase during which, similar to the preliminary phase of the Smart Grid plans, the Commission will provide guidance on the content of the distributed resources plans. (Rulemaking, pp. 4- 6, 10.)

However, unlike the Smart Grid proceeding, the Rulemaking provides for a very short time frame for filing of distributed resources plans following the final Commission guidance on the plans (only five months between late January, 2015 and July 1, 2015), and also provides that the Commission "guidance" will be in the form of a "ruling" rather than a Commission decision. In contrast, the CPUC 's Smart Grid process included a Commission decision (not a ruling) providing guidance on the content of Smart Grid plans over 12 months before the deadline for filing of the plans.

PG&E does not object to the preliminary schedule for Commission guidance in the Rulemaking; the Legislature, not the CPUC, set the July 1, 2015, filing deadline for utility distributed resources plans. However, given the short time required for filing distributed resource plans after the proposed Commission guidance ruling in the Rulemaking, PG&E recommends that the Commission precisely and carefully scope the preliminary phase of the proceeding in order to avoid issues that are outside the scope of Public Utilities Code Section 769 or that can be better evaluated and considered in the subsequent formal phases of the proceeding when the utilities' plans are evaluated and specific investments and spending proposals are considered in utility GRCs. In addition, the Commission should manage the preliminary "guidance" phase to avoid confusion or duplication with other pending Commission proceedings where various operational and technical issues associated with distributed resources are being actively evaluated and considered.

III. CONCLUSION

PG&E appreciates the opportunity to provide initial comments on the scope and content of distribution resources plans required to be filed by utilities under Public Utilities Code Section 769. PG&E looks forward to working with other interested parties, the Commission and Commission staff as the planning process moves forward.

Respectfully Submitted,

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APPENDIX A –
PG&E RESPONSES TO QUESTIONS
PRESENTED IN SECTION 3.1 OF R.14-08-013

1) What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

PG&E Response:

The Commission should be guided by the specific statutory criteria included by the Legislature in Public Utilities Code Section 769, including the requirement that the evaluation of the locational benefits and costs of distributed resources located on the distribution system must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings that distributed resources provide to the electric grid or savings in costs to utility customers. (PU Code Section 769(b)(1).) In addition, the Commission should use the specific technical safety and reliability criteria summarized in PG&Es' response to the additional questions below. The Commission should evaluate any spending proposed by the IOUs in their plans and rate cases based on whether utility customers would realize net benefits and the associated costs are reasonable.

The Commission should guide its review of utility plans based on the following principles:

- **Establish a common and shared understanding of the current distribution systems' capabilities:** An evaluation of proposed changes and improvements to the distribution systems of the respective utilities should first establish a common understanding of the capabilities of the existing systems. A threshold evaluation of the ability of the existing distribution systems and distribution planning processes to accommodate a reasonable range of projected distributed resources over the next ten years should be part of the Commission review of the plans.

- **Evaluation of improvements and potential investments to accommodate expected levels of distributed resources:** After establishing the baseline of the current systems' capabilities, the evaluation of improvements and investments that may be necessary to accommodate a reasonable range of projected distributed resources should incorporate agreed-upon metrics which evaluate cost-effectiveness, reliability, safety and customer satisfaction.

- **Integration of DER:** In addition to considering the potential contributions of DER with respect to optimizing grid operations, the Commission's evaluation should also recognize and address how to mitigate operational challenges.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

PG&E Response:

As discussed in the response to 1), above, the DRP should include all the specific elements that are expressly required by Public Utilities Code Section 769, as follows:

- The scope of each DRP should include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

- Each DRP should identify optimal locations for the deployment of distributed resources.

- Each DRP should evaluate locational benefits and costs of distributed resources located on the distribution system, based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

- Each DRP should propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

- Each DRP should propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

- Each DRP should identify any additional utility spending necessary to integrate cost effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers. However, any utility spending on distribution infrastructure to accomplish the DRP must be considered as part of the utility's next general rate case after approval of the DRP by the Commission, and the Commission may only approve the additional spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable.

- Each DRP should identify barriers to the deployment of distributed resources, including without limitation, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

PG&E Response:

While there may be numerous objectives for defining the optimal locations for DERs, PG&E offers the following two key guiding principles for developing criteria and methodologies for such optimal locations.

1. **Optimal locations can be interpreted as the areas where new DERs can be interconnected with minimal need for additional investment by the distribution system owner to ensure the system can continue to be operated safely and reliably.**

   To identify such optimal locations, the following are some key criteria:

   - **Type and size of conductor source-side (upstream) from the point of interconnection (POI).** All else remaining equal, larger conductor sizes will accommodate more DERs with minimal increase in system costs. Concentrations of DERs on circuits with smaller conductor sizes may have significant impacts on system costs.

   - **Circuit distance to substation from POI.** All else remaining equal, connecting DERs closer to the distribution substation minimizes increases in system costs. The further from the substation the POI is located the greater the distribution system impact. Connecting to a feeder near the end-of-line will tend to result in the highest distribution system impact and highest cost.

   - **Distributed Generation Penetration on the relevant line section.** All else remaining equal, a lower ratio tends to result in lower system impact. Rule 21 already establishes the fast track requirement of 15% aggregate generation facilities capacity to line segment peak load in order to allow fast track interconnection.

   - **Number of protective and voltage regulation devices upstream of the POI.** All else remaining equal, the distribution system impact will be less if there are fewer protective and voltage regulation devices source-side (upstream) from the DERs' POI.

2. **Optimal locations can also be interpreted as the areas where new DERs can provide capacity and/or reliability benefits to the distribution system.**

   - **Locations where projected load growth may require investment to increase circuit, bank or substation capacity to safely and reliably serve customers.** All else remaining equal, DERs that reduce projected distribution load growth in constrained areas have the potential to reduce or defer the need for investment to expand distribution capacity.

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

PG&E Response:

The locational value of DERs may vary widely depending on various stakeholders' perspectives. As stated in the PUC 769 language: Each DRP should "evaluate locational benefits and costs of distributed resources located on the distribution system, based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to all ratepayers of the electrical corporation."

Equity and fairness in utility rate design requires that rates to retail customers be primarily based on cost-causation. That is, customers whose forms of electric service, such as customer-owned or operated DERs, are unique and different from the general forms of electric service provided other customers, should pay for the unique and different costs to serve them, and other customers should not be allocated the costs that are unique to those customers with DERs. Likewise, the costs of utility service to customers with DERs should be offset by any unique grid-related or resource costs that the IOU avoids directly as a result of the customers' ownership or operation of DERs. Each utility's general rate cases are the appropriate forum for determining the equitable and fair allocation of the costs and benefits of DERs between DER owning customers and other customers.

For DERs that are not customer-owned, it is important to determine what types of compensation are already being provided to DERs and weighing that against the value being provided. For example, if a DER is participating in a wholesale procurement program like the Renewable Auction Mechanism or ReMAT programs, the compensation has already been largely determined, and locational benefits in addition to RAM or ReMAT compensation should be considered and evaluated through the definitions of the procurement program.

For some DERs, existing incentive programs may already be providing compensation to incent DER adoption. It may make sense to enhance the qualification requirements without adjusting compensation. An example of this can be found in the Rule 21 OIR, where Smart Inverter standards are becoming the norm/requirement and may provide indirect benefits to the DER owner or operator.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

PG&E Response:

As a preliminary response and in addition to the specific criteria listed in the responses to Questions 1 and 2, including cost-effectiveness and avoided cost, the integration of DERs into IOU distribution planning and operations should take into account the following specific considerations and methodologies:

- **IOU distribution planning and operations should be responsive to customer preferences and choices of preferred customer-owned or operated DERs.** To the extent that IOU customers prefer and choose customer-owned or operated DERs to serve their retail electricity needs, IOUs should provide convenient, expedited and cost-effective methods and criteria for interconnecting those DERs to the grid in order to satisfy the preferences of their customers.

- **IOU distribution planning and operations should mitigate operational challenges associated with intermittent DERs consistent with system safety and reliability needs**. In addition to avoided costs and direct benefits that DERs may provide, DERs also may present operational challenges that IOU distribution planning should address and mitigate, including: a) surplus generation in day-time hours requiring increasing amounts of DER curtailment to avoid over-generation, and reliability problems; b) increasing amounts of flexible ramping capacity to accommodate incremental amounts of intermittent DERs increasing the evening ramp when solar generation decreases while the evening peak increases; c) increasing amounts of flexible capacity to cover forecast deviations and variability of intermittent generation during the operating day; and d) diminishing value of incremental intermittent DER additions due to decreasing contributions to reliability and decreasing energy value of the DER additions as the hours of residual need shift to later hours in the afternoon with increasing amounts of DER additions.

Methods for applying these considerations include:

- Establishing processes to align planning w/forecasted DER growth
- Ensuring that the planning process reconciles or recognizes the long-term timeline for planning process (5 years) and uncertainty around DER materialization/adoption
- For operations, recognizing the need to establish systems to address the increased need to coordinate utility asset operations with DERs
- Establishing an integrated DER forecasting process.

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

PG&E Response:

Any distribution reliability services provided by DERs directly to support the safe and reliable operation of an IOU's electric distribution and transmission system can be evaluated generally in the DRPs and then implemented either in direct tariff changes or in the CPUC general rate cases and FERC transmission owner rate cases, where the IOU's proposed reliability-based investments and costs of service are evaluated using an appropriate risk-based methodology. Likewise, any reduction in electric distribution reliability attributable to DERs that causes increased costs to the IOU can be considered in the IOU's relevant rate design proceedings, in order to ensure that such incremental costs are appropriately allocated between DER-owning or operating customers and other customers.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

PG&E Response:

As provided by Public Utilities Code Section 769, the types of benefits that should be evaluated in distribution system planning and operations should include locational benefits of distributed resources located on the distribution system, based on reductions in local generation capacity needs, avoided investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electric grid.

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

PG&E Response:

Establishing the framework for evaluating the strategies proposed in the IOU DRPs is a critical step and should be completed before the DRPs are developed and submitted. This framework should describe credible potential future scenarios that can be used to model DRP strategy performance as well as the specific metrics and standards which will be used to quantify a given strategy's performance in each scenario. Establishing performance metrics is as important as defining the scenarios, and often will inform what scenarios are most important to study. These metrics must be widely accepted and unbiased measures of important aspects of overall system performance on cost, reliability, safety and environmental impacts.

Where possible, the scenarios for evaluating the DRPs should be coordinated with and informed by other efforts to establish consistent scenarios for other planning activities in California (e.g. the Integrated Energy Policy Report, Transmission Planning Process and the utilities' Long-Term Procurement Plans). In those proceedings, a number of key inputs or assumptions which have a major impact on future demand, resources and system operations have been established. Where the key factors underlying a major input are uncertain, several forecasts are typically developed or referenced (e.g. from Long Term Procurement Plan or Integrated Energy Policy Report forecasts) to enable testing of system performance across the range of conditions that may occur. For example, various forecasts are used to capture the uncertainty associated with weather and economic growth in future years.

The first step is to identify those inputs which are key drivers of DRP performance and especially those key drivers which are highly uncertain. For those uncertain key drivers, a range of values should be developed or adopted from other analyses or proceedings. These are likely to include load assumptions (peak, energy and profile) and other factors which are specific to distribution planning, such as EV penetration and geographic distribution, and market-driven DG penetration and geographic distribution.

The number of key drivers will likely preclude analyzing DRPs against all possible combinations of inputs. To streamline the development and assessment of the proposed DRPs, scenarios which are likely to have the same result should be consolidated and emphasis should be placed on those scenarios which are most likely ("trajectory" scenarios) and those which represent possible conditions that impose stress on the system. The latter scenarios can be used to identify least-regrets strategies whose costs are outweighed by their ability to avoid costly reliability shortcomings in the event that the future stressors do materialize.

As with other planning exercises in California, stakeholders should have the ability to provide input and recommendations throughout the process of establishing an evaluation framework. It is critical that the process be transparent to stakeholders and that the underlying inputs are accessible and public to the extent possible. While it is beneficial to have a common set of scenarios for evaluating multiple DRPs, the utilities should have the ability to develop variations on the common scenarios. This may be needed, for example, where a DRP incorporates a strategy which changes a key assumption (e.g. a program that results in a different load shape). Being able to develop variations on the common scenarios will enable a wider variety of strategies to be characterized and evaluated.

9) What types of data and level of data access should be considered as part of the DRP?

PG&E Response:

Each IOU's DRP should provide for open and non-discriminatory access by DER owners and operators to necessary electric distribution planning and reliability data needed to interconnect DERs and provide grid services, consistent with the Commission's rules to protect the privacy of customer-specific information and the confidentiality of market-sensitive, proprietary and other sensitive information. See, e.g., Public Utilities Code Sections 8380, 454.5(g), 583.

Development of the DRP should consider all publicly available data related to generation interconnections and electric distribution planning. The following publicly available data includes:

- Distribution Interconnection Handbook – Handbook that provides interconnection requirements, such as metering and service line installations
- Generation interconnection process information (including application process and associated forms)
- Generation interconnection queue (listing of all wholesale, Rule 21 non-exporting and Rule 21 exporting (with PURPA PPA) projects that have initiated the interconnection application process.
- Solar Photovoltaic (PV) Renewable Auction Mechanism (RAM) Map is a geographical map that provides facility locations and names of electric lines and substations, as well as operating characteristics including operating voltage, facility capacity and existing interconnected distributed generation.
- List of demand-driven distribution projects from the GRC Phase II
- Local Capacity requirements from the annual Transmission Planning Process

Other sources of data that could be made available, subject to customer consent, are completed Pre-Application Reports. Currently, under the Rule 21 tariff, potential interconnection customers can request a Pre-Application Report for a non-refundable fee of $300. This report provides a summary of the existing distribution capacity, as well as specific details, such as nominal distribution voltage, peak load and min load estimates, number of protective devices on a circuit, among other information, for a specific location (e.g. potential point of interconnection for generation). The Pre-Application Report only provides pre-existing data at the time a customer requests such a report.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

PG&E Response:

The DRP can outline the principles and general direction on how higher levels of each DER can be incorporated into the distribution planning and operations processes. Generalized examples may be useful for expository purposes. Specific measures or projects may be appropriate at a later time during the evaluation of additional spending proposals as part of the utility's General Rate Case.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

PG&E Response:

PG&E recommends that DRPs and the investments and operations that implement DRPs be monitored in each IOU's general rate case, where electric distribution investments and operations are periodically monitored and updated.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

PG&E Response:

The Commission should apply the statutory principles required by Public Utilities Code Section 769, as well as the other principles listed by PG&E in response to Questions 1 and 2, above.

13) Should the DRPs include discussion of how ownership of the distribution system may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

PG&E Response:

Pursuant to Public Utilities Code Section 769, the DRPs will include an evaluation of standard tariffs, contracts and other mechanisms by which owners or operators of DERs can provide electric distribution reliability and support services to IOUs under the IOUs' electric distribution plans.

14) What specific concerns around safety should be addressed in the DRPs?

PG&E Response:

DERs, like any other resources, facilities, or equipment that interconnects with the electric distribution system or are provided services by the electric distribution system, must comply with all relevant safety, reliability and security requirements applicable to the integrated electric system. The DRPs should acknowledge and take into account these standard safety, reliability and security requirements that are included in utility and CPUC-approved tariffs and general orders.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

PG&E Response:

PG&E has identified no further actions at this time that the Commission should consider in order to comply with Section 769, but will assess and provide additional comments on the appropriate scope of DRPs as this Rulemaking moves forward.

16) Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

o Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework', what additions or modifications would you suggest be made to this framework?

PG&E Response:

PG&E supports moving toward a future that not only includes an appropriate level of DER adoption to meet utility customers' needs and preferences, but one where the all of the customers who rely on PG&E's distribution system to meet their energy needs can realize the potential benefits of DER adoption in a cost effective way.

In the future, as today, PG&E's electric distribution system will serve the needs and preferences of customers for a wide range of DER adoption. This range includes those customers who do not actively adopt DERs as well as those who rely on a high level of DER devices to meet some of their energy needs and rely on PG&E's for others. As the mix of DER adoption levels among PG&E's customers evolves, PG&E will need to ensure that its distribution system remains effective at providing safe, reliable and affordable service to all of its customers.

PG&E supports developing a framework to support and enhance its long-term distribution system planning efforts that includes reasonable long-term scenarios of DERs deployment. Such a planning effort should lead to identification of optimal locations and investments in its distribution system that will enable a wide variety of future DER adoption scenarios.

In addition, the paper should recognize that, while new demand response programs focused on mitigating issues related to intermittent generation may prove useful and should be developed, traditional peak shaving and emergency demand response programs will continue to remain relevant and provide value for customers for the foreseeable future

PG&E expects to provide additional recommended modifications to the proposed framework as the informal collaborative process moves forward.

o Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?

PG&E Response:

The *More Than Smart* paper identifies the need for both a baseline evaluation of the current capabilities of the electric distribution system as well as the development of potential future scenarios for the purpose of stress testing the baseline capabilities of the distribution system. PG&E supports both these efforts and view them as essential prerequisites to DRP development. As noted in PG&E's response to question 8, we recommend that both trajectory and stress scenarios be developed and coordinated and informed by other planning activities in California.

In the discussion of scenario development, the paper suggests that the IOUs should "incorporate assumptions related to state policy goals (e.g. 12,000 MWs of local DG, 1.5 million ZEVs, 5% of peak met by DR) and that these assumptions could be augmented by insights from stakeholders and research analysis by Lawrence Berkeley National Lab (LBNL) along with other research organizations as well as scenarios developed in related California proceedings and planning" (pg 10). Specific state goals may evolve over time as post AB32 targets are established, and the actual amount of DER penetration could vary significantly from these goals. PG&E recommends that this potential variability be taken into account in the scenario planning activity to help understand the impacts of these various potential future states.

Additionally, the paper seems to assume that the CPUC AB 327 process can establish "comprehensive" statewide electric distribution planning criteria and goals to support distributed energy resources. However, AB 327 only covers investor-owned electric utilities, and thus the

AB 327 distributed resource plans will not be comprehensive unless they cover the local publicly-owned utilities and irrigation districts which control over one-third of the electric transmission and distribution grid in the State.

o Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?

PG&E Response:

This section of the paper notes that the IOUs' current electric distribution systems are not designed to accommodate expected levels of distributed resources over the next decade, and that the optimal design for an electric distribution system is an "open network" design rather than the current design. As noted above, PG&E recommends that the baseline assessment of the capability of the existing distribution system is necessary to determine first how current IOU distribution systems are accommodating growth in existing distributed resources. As part of the AB 327 evaluation of optimal locations for distributed resources, the DRPs can evaluate the baseline capability of current electric distribution systems and the costs and benefits of investments in system upgrades or changes that will accommodate forecast growth in distributed resources.

The DRPs should compare current planned investments in the IOUs' electric distribution systems with all reasonable DER adoption scenarios, and determine whether additional investments may be required based on the reasonably forecast market penetration of distributed resources. Assessing the capabilities of the current system and the near-term investments to maintain its reliability to meet the needs of a variety of DER adoption forecasts must be the cornerstone of any DRP development and analysis in order to comply with the cost-effectiveness criteria in AB 327.

o Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?

PG&E Response:

The paper discusses the potential role of third-party "distribution system operators" (DSOs) to provide retail electricity distribution services independent of the current regulated retail investor-owned electric utilities. PG&E needs more information and specificity on the perceived need and benefits of such a structural change and role for non-utilities before it can comment on the potential role of such non-utility DSOs.

o Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?

PG&E Response:

At this time, PG&E has no additions or modifications to suggest, but looks forward to ongoing development of the planning framework.

o Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?

PG&E Response:

At this time, PG&E has no additions or modifications to suggest, but looks forward to ongoing development of the planning framework.